BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769	R.14-08-013 August 14, 2014

COMMENTS OF THE CALIFORNIA ENERGY STORAGE ALLIANCE ON ASSIGNED COMMISSIONER'S RULING RE DRAFT GUIDANCE FOR USE IN UTILITY AB 327 (2013) SECTION 769 DISTRIBUTION RESOURCE PLANS

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The California Energy Storage Alliance ("CESA") [1] hereby submits these reply comments pursuant to the Rules of Practice and Procedure of the California Public Utilities Commission ("Commission") on *Assigned Commissioner's Ruling re Draft Guidance for Use in Utility AB 327 (2013) Section 769 Distribution Resource Plans*, filed November 17, 2014("Ruling").

[1] 1 Energy Systems Inc., Advanced Microgrid Solutions, AES Energy Storage, Alton Energy, American Vanadium, Amperex Technology Limited, Aquion Energy, ARES North America, Beacon Power, LLC, Bosch, Bright Energy Storage Technologies, Brookfield, CALMAC, Chargepoint, Clean Energy Systems, Coda Energy, Consolidated Edison Development, Inc., Cumulus Energy Storage, Customized Energy Solutions, Demand Energy, DN Tanks, Duke Energy, Eagle Crest Energy Company, EaglePicher Technologies, LLC, East Penn Manufacturing Company, Ecoult, EDF Renewable Energy, Energy Storage Systems, Inc., Enersys, EnerVault Corporation, EV Grid, FAFCO Thermal Storage Systems, FIAMM Energy Storage Solutions, Flextronics, Foresight Renewable Solutions, GE Energy Storage, Green Charge Networks, Greensmith Energy, Gridscape Solutions, Gridtential Energy, Inc., Halotechnics, Hitachi Chemical Co., Hydrogenics, Ice Energy, Imergy Power Systems, ImMODO Energy Services Corporation, Innovation Core SEI, Inc. (A Sumitomo Electric Company), Invenergy LLC, K&L Gates, KYOCERA Solar, Inc., LG Chem, LightSail Energy, LS Power Development, LLC, Mitsubishi International Corporation, NEC Energy Solutions, Inc., NextEra Energy Resources, NRG Solar LLC, OCI, OutBack Power Technologies, Panasonic, Parker Hannifin Corporation, PDE Total Energy Solutions, Powertree Services Inc., Primus Power Corporation, Recurrent Energy, Renewable Energy Systems Americas Inc., Rosendin Electric, S&C Electric Company, Saft America Inc., Samsung, SEEO, Sharp Electronics Corporation, SolarCity, Sony Corporation of America, Sovereign Energy, STEM, Stoel Rives LLP, SunEdison, SunPower, TAS Energy, Toshiba International Corporation, Trimark Associates, Inc., Tri-Technic, UniEnergy Technologies, LLC, Wellhead Electric. The views expressed in these comments are those of CESA, and do not necessarily reflect the views of all of the individual CESA member companies. See, http://storagealliance.org.

I. INTRODUCTION.

In these comments CESA provides observations and makes recommendations to the Commission that follow the structure of Attachment A to the Ruling entitled *Draft Guidance Document for R.14-08-013*, referred to in the Ruling as the *Draft Distribution Resource Plan Guidance* ("Guidance"). CESA applauds the practical approach of the "New Framework for Distribution Planning" described in Part 1 of the Guidance. It is very well thought out and will result in real progress, especially because of the requirement to implement near term demonstrations and "learn by doing."

II. PART 3: COMMISSION OVERSIGHT' SHOULD INCLUDE DEVELOPMENT OF LOCAL AND SYSTEM PERFORMANCE METRICS TO ENSURE THE GOALS STATED IN PART 1 ARE ACHIEVED OVER TIME.

Oversight should include a recommendation for the utilities to develop a shared set of top-level local and system performance metrics that can be tracked by utility over time to help ensure that progress toward goals of this proceeding are being achieved. Metrics could include, for example, reliability and safety, greenhouse gas ("GHG") reduction, distributed energy resource ("DER") penetration, average load factor, ratepayer impact, capacity of third party-owned DERs under contract, and so forth.

As stated in Part 1 of the Draft Guidance, "there appears to be general agreement that this should really be an on-going, cyclical process that will repeat over time to incorporate how technologies and market policies are evolving and to take advantage of lessons learned in previous cycles," (page 6). CESA agrees with this statement, and strongly supports the Guidance's recommendation to adopt a biennial Distributed Resources Plan ("DRP") filing cycle. Because this process will last many years - even decades -- it is important to track and focus on specific outcomes to ensure that the core goals of AB 327 and this proceeding are met over time,

namely to "minimize overall system costs and maximize ratepayer benefit from investments in distributed resources" while simultaneously "meeting California's policy of significantly reducing GHG emissions from the State's electricity and transportation systems." (Part 1 Introduction, page 4) CESA would like to emphasize the importance of tracking not only "local" but also "system" level goals to ensure that DERs are achieving this overarching objective as stated in the Guidance.

III. THE DISTRIBUTED RESOURCES PLAN'S SHOULD ENCOURAGE UTILITIES TO PROPOSE INCENTIVE COMPENSATION MECHANISMS FOR THEIR SHAREHOLDERS IF LOCAL AND SYSTEM LEVEL PERFORMANCE METRICS ARE ACHIEVED.

Utility progress measured against the metrics described above should be compensated. The rationale for this is that if the metrics are appropriately designed, then achieving these metrics would be in the interest of ratepayers. Further, the intent and spirit of Public Utilities Code Section 769 requires the "Commission, the Utilities, consumers and new services providers… to work cooperatively to revise existing incentives and tariffs to promote DER in locations that will provide the greatest net benefits to the grid. These benefits include enhanced reliability of delivery and the opportunity to introduce innovation – whether driven by the Utilities or by non-traditional arties – into the utility of the future," (page 5). As publicly-traded regulated monopolies, the compensation of utilities and their shareholders cannot be ignored. Innovation necessarily means undertaking new and greater risk, and it is unlikely that any enterprise would be willing to do so without the promise of a commensurate reward for that risk. Utility shareholders should be fairly compensated for undertaking this additional risk, which has not traditionally been borne by their shareholders.

Further, as a practical matter, there are so many ways in which the utility's proactive cooperation will ensure a successful outcome for more fully incorporating DERs into distribution

planning and operations: distribution system capacity, avoided costs, customer load data and access to other key system information, interconnection, tariff and other contracting structures, and demonstration and deployment just to name a few. Aligning the interests of utility shareholders with those of this proceeding (and other stakeholders) is a very key foundational requirement that will make a profound difference in the outcome of this proceeding, and should not be ignored.

IV. PRIORITY OPTIMAL DISTIBUTED ENERGY RECOURCE LOCATIONS SHOULD BE SCREENED BASED ON BOTH AVOIDED COST AND BENEFIT, AND EVALUATED BASED ON LOCAL AND SYSTEM BENEFITS DELIVERED.

The Optimal Location Benefit Analysis described at page 16 that is used to identify optimal DER locations properly requires utilities to specify the net benefit, including avoided costs, that DERs can provide in a given location. However, CESA recommends that the recommended process for identifying and prioritizing optimal locations should be expanded in several ways.

First, it should be clarified that optimal geographic locations for DERs are based not only on avoided costs, but also *benefits*, which may not be historically tracked from a distribution system planning standpoint. For example, optimal locations for DERs could be identified and prioritized based on local pollution and health impacts (*e.g.*, prioritizing non-attainment areas) and regions where there are reliability (subject to frequent routine outages) or resiliency (subject to frequent major outage) grid issues.

Avoided costs *and* benefits are *both* important given the goals of AB 327 and the goals of the DRPs as stated in the Guidance.[2] Gross screens can be utilized to identify priority substations first, before looking at each substation location more granularly to identify an optimal "mix" of DERs. For example, gross screens could include filters to identify regions with very poor air quality (prioritizing environmental goal attainment) and/or low-income regions (prioritize environmental justice). Both of these screens would prioritize benefits that are not considered by utilities in traditional distribution planning processes.

Further, in addition to including both avoided costs and benefits, prioritizing target near-term substations that should benefit from deployment and demonstration of DERs and subsequently evaluating their cost-effectiveness should factor in the full stack of local *and system* benefits. For example, DER optimization and cost-effectiveness analysis should use modeling that quantifies the system level benefits of DERs, including, but not limited to, greater efficiency of the existing fossil generation fleet, better utilization of renewable energy (less curtailment of renewable energy), better utilization of transmission and distribution systems, and reduction of GHGs associated with these system level impacts. These system level benefits can be approximated leveraging existing analysis at the transmission node level. These system level benefits are not included in traditional customer or distribution level cost-effectiveness analysis, but are a very real and important value delivered by DERs.

Thus, the DRPs need to formulate specific recommendations to inform existing system level modeling efforts to quantify system benefits of DERs (*e.g.,* in general rate cases, or in long term procurement planning) as a second step to determine a full stack of benefits from DERs.

[2] "[M]inimize overall system costs and maximize ratepayer benefit from investments in distributed resources" while simultaneously "meeting California's policy of significantly reducing GHG emissions from the State's electricity and transportation systems." (Part 1 Introduction, page 4).

CESA recommends that the near term focus be on quantifying local benefits, but it is very important as a follow-on step to appropriately, and fairly allocate system benefits and quantify as much as possible the other benefits that result from DERs to determine their overall cost-effectiveness.

Regarding forward looking scenarios, CESA supports recommended ten-year utility modeling scenarios based on the Integrated Energy Policy Report ("IEPR"), but strongly recommends that additional scenario modeling be included for specific scenarios regarding stationary energy storage, including integration of stationary energy storage for electric vehicle ("EV") grid integration applications. The 2014 IEPR did not adequately analyze these scenarios - particularly in light of recent developments regarding Self-Generation Incentive Program ("SGIP") reauthorization (SB 861), Southern California Edison Company's Track 1 LCR procurement (261 MW of energy storage) and ongoing energy storage requests for offers ("RFO's") issued pursuant to AB 2514.

V. PRIORITY LOCATIONS FOR DEMONSTRATION AND DEPLOYMENT OF DISTRIBUTED ENERGY RESOURCES SHOULD BE FURTHER ANALZYED FOR OPTIMAL COMBINATION OF SERVICES REQUIRED.

CESA recommends that a second order analysis be undertaken to better understand and quantify the optimal "combination of services" that would optimize any particular substation or feeder distribution line. Ideally, this could be done for prioritized substations for demonstration purposes early on in this proceeding. Clarity on these needed services and their value would highlight ways in which energy storage and other DERs may be utilized to optimize the baseline distribution system itself, and also help facilitate the deployment of cleaner sources and uses of electricity. For example, energy storage could be used to help reduce interconnection costs and expand existing circuit capacity to integrate more distributed renewables and EVs.

It would be helpful to have the utilities explicitly evaluate operational constraints and related costs to manage the cost of renewable energy and DER integration, and in so doing, help surface opportunities where energy storage can enable DER. These constraints and costs may not necessarily be factored into the *status quo* distribution plan baseline. In these cases, energy storage could be a substitute for necessary incremental transmission and distribution upgrades. In summary, energy storage needs to be evaluated differently from distributed generation and demand response ("DR"), because it can behave like generation and like load from the *same asset*.

Energy storage could go into the baseline determination (*e.g.,* energy storage can be used as a distribution asset as part of the *status quo* and energy storage can also be used as a solution for incremental intermittent generation additions). Energy storage also has option value to distribution systems. This has never been done before – so demonstrating this for a single distribution planning area and the evaluation and planning steps to determine the optimal DER mix is a very good idea. (See comments below on Demonstration and Deployment).

VI. CESA STRONGLY SUPPORTS NEAR TERM DEMONSTRATION AND DEPLOYMENT TO FACILITATE "LEARNING BY DOING" AND RECOMMENDS THAT SUCH DEMONSTRATIONS BE REQUIRED TO INCLUDE INNOVATIVE CONTRACTING MECHANISMS WITH THIRD PARTIES.

CESA strongly supports the Guidance's requirement for Demonstration and Deployment, discussed at page 17. Because what is contemplated in this proceeding has never been done before, there is literally no substitute for "learning by doing." CESA respectfully recommends that the Demonstration and Deployment element of the Guidance be revised to also include the addition of a new section, which would require the utilities to demonstrate scalable competitive

RFOs and contracting mechanisms for utilities to procure distribution level services from third party-owned assets, consistent with the goal stated at page 3-4:

> "Since 2001 the Public Utilities Code has provided that "[e]ach electrical corporation, as part of its distribution planning process, shall consider non-utility owned distributed energy resources as a possible alternative to investments in its distribution system in order to ensure reliable electric service at the lowest possible cost"

Creating standard contracting mechanisms that are bankable and financeable are a key foundation to achieving "a distribution grid that is "plug-and-play" for DERs (discussed at page 5). A good example of this is the recently announced behind-the-meter contracts proposed for local capacity under SCE's Track 1 LCR RFO (announced November 5, 2014). However, there is much to be learned going forward for expanding creative DER contracting mechanisms. Regarding Section 4, Tariffs and Contracts (page 22), CESA recommends explicitly adding the need for DRPs to "propose multi-year contracting mechanisms for third party-owned resources." This requirement should also explicitly clarify that behind-the-meter DERs such as energy storage are included, since behind-the-meter applications of energy storage have been excluded from recent RFOs.[3] There are various approaches for accomplishing this:

a. Long term contracts for aggregated capacity, similar to what SCE has done in its Track 1 LCR procurement.

b. Innovative new retail DR programs for retail customers. CESA further recommends adding language that expressly supports including within these DR programs the ability for distributed energy storage to provide export of energy during DR events. Current residential DR rules limit energy storage exports to

[3] All three of California's investor owned utilities issued RFOs on December required by AB 2715 and Commission decision (D.)14-10-045, and all three excluded behind the meter energy storage from consideration (as they had the option to do).

only offsetting on-site load. Those same energy storage assets could be cost-effectively utilized to provide additional support to address local or system needs.

c. San Diego Gas & Electric Company's VGI Pilot tariff could be considered a good starting point for a rate structure accounting for system and distribution level benefits through retail rate design. This tariff design could be extended to a bi-directional model, assuming there is a mechanism for utilities to capture fixed costs of providing access to the transmission and distribution systems.

Similarly, CESA suggests adding another category of barrier at Section 6 - Barriers to Deployment – which includes "commercial contracting" – inadequate or absence of clear commercial contracting mechanisms for procuring specific distribution system services from third parties (the utility owned, rate based case is already commercially very clear).

Finally, CESA recommends clarifying that the definition of Customer Side Energy Storage (page 27) – which can include aggregated small energy storage systems at residential and commercial locations. The CAISO has already launched a new metering and telemetry stakeholder initiative on November 10, 2014 called "Expanding Metering and Telemetry Options Technical Stakeholder Initiative" to explicitly and cost-effectively include small behind-the-meter systems on an aggregated basis in its markets.

VII. PART 2: IDENTIFICATION OF RELATED PROCEEDINGS SHOULD INCLUDE COORDINATION WITH RELEVANT PROCESSES AND INITIATIVES AT THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR.

CESA applauds the thoughtful consideration of other interrelated Commission proceedings and processes that overlap this proceeding that is evidenced in the Guidance. In addition, CESA respectfully suggests that the following stakeholder processes underway at the California Independent System Operator ("CAISO") should also be included, particularly as

those proceedings are contemplating ways in which customer-sited or distribution-interconnected resources, such as energy storage, can provide wholesale market services:

a. Energy Storage Roadmap Initiative

b. Transmission Planning Process

c. Energy Storage Interconnection Initiative

d. Expanding Metering and Telemetry Options Technical Initiative

e. Flexiramp Initiative

f. Flexible Resource Adequacy Must Offer Obligation ("FRAC-MOO") Initiative

g. Load Granularity Refinements Initiative

h. Capacity Procurement Mechanism Replacement Public Settlement Negotiation

i. Reliability Services Working Group

VIII. CONCLUSION.

CESA appreciates this opportunity to submit these comments on the Ruling, and looks forward to working with the Commission and stakeholders in this proceeding.

Respectfully submitted,

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